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FACSIMILE COVER SHEET

OFFICE OF GENERAL COUNSEL

DATE: April 27, 1999

TO: David S Guzy 303/231-3385

FROM: David Deal PHONE: 202/682-8261(o)

SUPPLEMENTAL MESSAGE: Part I

Will be sent in 2 parts

PAGES TO FOLLOW: 24 + COVER

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FAX MESSAGE

Date: April 27, 1999

From: David T. Deal

To: David S. Guzy
Chief, Rules and Publications Staff
Minerals Management Service
Royalty Management Program
303-231-3385 FAX
303-231-3432

Subject: Industry Comments on MMS Federal Crude Oil Valuation Rulemaking

Attached are the latest joint industry comments on the pending MMS crude oil valuation rulemaking.

For your information, I am sending a few copies to MMS headquarters in Washington, DC. I will be sending you a non-fax copy by overnight as well.

If you have any questions, please call me.

American Petroleum Institute

ipaa America's Oil & Gas Producers

Domestic Petroleum Council

US Oil & Gas Association

April 27, 1999

Lucy Querques Denett
Associate Director, Minerals Management Service
United States Department of the Interior
1849 C Street, NW
Washington, DC 20240

Comments in Minerals Management Service
Federal Crude Oil Valuation Rulemaking

Dear Lucy:

On behalf of the American Petroleum Institute (API), the Independent Petroleum Association of America (IPAA), the Domestic Petroleum Council (DPC) and the United States Oil and Gas Association (USOGA), these comments augment the discussions held at the MMS public workshops held March 23 (Houston), March 24 (Albuquerque) and April 6-7, 1999 (Washington, DC).

We were encouraged at the MMS staff's willingness to discuss the substance of the MMS' present proposal and industry's recommended changes. We believe these efforts can lead to a sound resolution of core issues presented by this rulemaking. To the fullest extent possible, the attached comments assemble in one package the elements of industry's point of view and answer questions that arose in the course of our discussions.

Our specific comments are organized along the lines of the key issue areas used as the organizing structure for the workshops:

For **arm's length transactions**, we urge the MMS to adopt in the regulations more specific criteria to guide lessee application of the control-based definition of "affiliate" in order to arrive at valuation methodology certainty at the outset of the process.

For **non-arm's length transactions**, we urge the MMS to expand its valuation methodology options to include comparable sales as a measure of value if the lessee satisfies prescribed information and sales volume requirements.

For **adjustments off downstream values**, we urge the MMS to adopt adjustments for transportation, location and quality, and midstream activities sufficient to make it possible to net back from downstream values (index or otherwise) and calculate a value for royalty purposes which more accurately approaches the value of production at the lease. Given the MMS's inclination to continue its reliance on a cost of capital recovery approach instead of commercial value, transportation allowances are especially problematic and we again urge the MMS to convene another workshop or a symposium to take a hard look at this complex issue which significantly affects the economics of OCS development. Such a forum would be an ideal opportunity to examine computation methodologies but, more important, would allow the MMS to ascertain how its transportation policy conforms with the exploration and development promoting elements of recent legislation and Administration initiatives, such as the Comprehensive National Energy Strategy.

For **second-guessing**, we urge that the MMS adopt language making it clear that the use of gross proceeds as the valuation methodology by lessees operating in good faith and engaging in arm's length transactions will not be set aside in favor of some other methodology (e.g., indexing) simply because some other entity was able to obtain a higher value for the sale of production. A strong presumption in favor of arm's length transactions would recognize that the lessee and the lessor have a mutual interest in obtaining the highest price for the sale of production and that a range of prices characterizes "market value." Such a presumption would, of course, in no way shield a lessee from full audit and would not permit demonstrable misconduct.

For **binding determinations**, we urge the MMS to adopt an explicit process by which lessees can procure timely valuation methodology determinations. Such determinations would be akin to IRS letter revenue rulings and the comparable rulings of other agencies. For example, they would be limited to the facts presented and have no precedential value. While binding, they would be revocable, although any changes would apply prospectively only.

* * * * *

Overall, we believe these recommendations as a package would move the MMS proposal closer to a final crude oil valuation rule that is workable and fair, while decreasing the cost of administration, decreasing appeals and litigation, and satisfying the legal requirement that royalty obligations be based on the value of production at the lease. To the extent the MMS still has concerns about achieving its objectives in this rulemaking, we submit that royalty-in-kind remains a powerful option that could avert many of the ambiguities inherent in any valuation methodology. In any event, we urge the MMS to carefully consider these recommendations and welcome any further questions you might have to reach a satisfactory resolution of this important rulemaking.

Sincerely,

David T. Deal
American Petroleum Institute

William F. Whitsitt
Domestic Petroleum Council

Ben Dillon
Independent Petroleum Association of America

Albert Modiano
United States Oil & Gas Association

American Petroleum Institute, Independent Petroleum Association of America, Domestic Petroleum Council and United States Oil and Gas Association Comments in Minerals Management Service Federal Crude Oil Valuation Rulemaking 64 FR 12267 (March 12, 1999)

To complement industry participation in the MMS public workshops in Houston (March 23, 1998), Albuquerque (March 24), and Washington, DC (April 6-7, 1999), industry submits the comments below. To the fullest extent possible, these comments do not repeat the voluminous comments we submitted earlier in the rulemaking that we incorporate by reference. These comments do, however, include as Appendix "**A**" materials (now paginated) employed during the 1999 workshops and as Appendices "**B**" – "**D**", new materials generated as a result of the workshop discussions.

At the outset, we should be clear that industry continues to believe that there is an active market at the lease which makes it unnecessary, except in extraordinary circumstances, to use netback-type valuation methodologies like the market center spot price methodology proposed by the MMS. This active market at the lease makes the universe of arm's length transactions far larger than the MMS rulemaking implies. This fact should make more transactions eligible for valuation as arm's length transactions themselves and should also make it practicable for valuation of non-arm's length transactions without recourse to the MMS' flawed indexing approach which the MMS would apply except for special situations in the Rocky Mountain region.[1]

A. Arm's Length Transactions

The gist of industry's recommendation is that MMS retain regulations that use control as the central principle, and augment the present percentage levels with specific criteria to help lessees seeking to determine whether the affiliation test is met.

Specifically, we recommend that the MMS adopt guidelines that state that the lessee has rebutted the presumption of control if he can demonstrate that:

- The affiliated entity can take any relevant action without an affirmative vote of the lessee; or
- If the lessee is a partner in a partnership but is not a general partner; or
- The lessee is a natural person not related within the fourth degree to the affiliated natural person; or
- The lessee has directors on the affiliated company's board of directors but the lessee's director cannot block any relevant action by the board.

See Appendix "**A**" at 2-4.

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[1] While too numerous to cite in these comments, the administrative record for this rulemaking is full of comments from large and small producers, crude oil marketers and respected economists that vigorously support the thesis that there is an active market at the lease which makes it unnecessary to use a downstream point as the starting point for valuation of most crude oil transactions.

At the April 7, 1999 workshop, two questions arose with respect to Industry's recommended criteria for rebutting the presumption of control. One involves the fiduciary responsibility of partners. The other one involves satisfying the proposed "opposing economic interests" requirement.

Fiduciary responsibility of partners. One of the participants at the workshop contended that a partner owning 10-50% of a partnership who is not a general partner could nevertheless "control" the partnership because a general partner is a fiduciary of the partnership and the other partners. Industry believes this concern is unfounded.

A general partner having a fiduciary duty to the partnership and the other partners must place the interests of the partnership and the other partners ahead of his own. However, if the partnership enters a contract with a partner acting in his or her individual capacity, the general partner's fiduciary duty would require him to place the partnership's interest ahead of those of the partner acting in his or her individual capacity.

For example, where the lessee is a partnership and contracts to sell lease oil production to an individual who also owns 10-50% of the partnership, the general partner's fiduciary duty to the partnership would require that the interests of the partnership be placed ahead of those of the partner dealing in an individual capacity with the partnership. In fact, a general partner placing a limited partner's individual interest ahead of the partnership's interests would actually breach his fiduciary duty.

Opposing economic interests. The proposed definition of arm's-length contract contains an "opposing economic interests" element: "*Arm's-length contract* "means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. . . ."[2]

Specifically, the MMS asked how a lessee who successfully rebutted the presumption of control might satisfy the "opposing economic interests" requirement. In contrast to the presumption of control that exists when a lessee owns a 10-50% in another entity, the proposed rule imposes no presumption of lack of opposing economic interests that the lessee must rebut.

A lack of opposing economic interests cannot be presumed; it must be established by MMS based on the facts surrounding the transaction. A lessee who has successfully rebutted the presumption of control should have no further burden of proof with respect to the "opposing economic interests" requirement. Where the presumption of control has been successfully rebutted, it would be illogical and unfair to use the affiliation of the parties in order to establish the lack of opposing economic interests. The criteria for establishing the lack of opposing economic interests should be no different for parties who have successfully rebutted the presumption of control than for those who have contracted with unaffiliated entities. Simply put, lack of opposing economic interests should be established based on criteria other than mere affiliation between the parties.

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[2] 30 CFR 206.101, as proposed at 63 FR 6113, 6126 (February 6, 1998).

As a separate but related arm's length transaction matter, Industry endorses MMS' efforts to accommodate the desire of lessees to pay royalty based on their arm's-length gross proceeds, less appropriate deductions. However, lessees should be given the option of utilizing the index netback methodology to value royalties for arm's-length sales in certain situations. Many lessees, both integrated and independent, do not sell their oil production to affiliates. However, these lessees do engage in numerous different types of dispositions (e.g., outright sales to third parties, buy-sell and exchange agreements, transfers to a refinery) that would require tracing production downstream.

B. Non-Arm's Length Transactions

The gist of Industry's recommendation is that the MMS adopt a menu of valuation options that should include a comparable sales option and could include a net back/index-type option for valuation of production in non-arm's length transactions. Overall, Industry believes that the market at the lease is active enough to generate sufficient comparable sales that would make recourse to a netback-type methodology unnecessary in most cases for valuation of production at the lease.

As presented at the workshops, the Industry-recommended comparable sales model would have the following elements:

- At least 20% of the lessee's production must be purchased or sold at arm's length to serve as the basis for valuation of non-arm's length production.
- Where a tendering or bid out-type system is used, a minimum of three bids would be required.
- The value used for valuation of the non-arm's length production would be based on weighted average prices of third party transactions.
- The value would be adjusted as necessary for transportation and quality.
- The valuation methodology would be subject to annual review by MMS.

See Appendix "A" at 5-9.

Such an approach builds on the MMS' own proposal for use in the Rocky Mountain region[3] and tracks the approach used by states and the MMS for royalty-in-kind. It avoids the unavailability of data problem identified by the MMS in connection with use of the current regulations' comparable sales benchmarks. It takes advantage of the high production volumes in the Gulf of Mexico. And using a large representative sample of arm's length transactions makes it possible to avoid the inherent complexity of calculating lease-market center differentials while focusing on the value of production at the lease.

[3] The MMS proposal for non-arm's length valuation in the Rocky Mountain region is unduly limited in many significant respects but does recognize the value of alternative valuation pathways. See, e.g., API's April 1998 comments on the MMS' February 1998 supplementary proposal at 2-5.

At the March-April 1999 MMS workshops, the MMS posed two questions: One involved the 20% production volume minimum. The other involved which arm's length transactions would be included in the weighted average of comparable sales.

Minimum production volume. The MMS has suggested that a production volume threshold higher than the 20% might make a comparable sales approach more acceptable. Following its own February 1998 proposal, and relying on a Rocky Mountain Oil and Gas Association (RMOGA) survey of state severance taxes,[4] the MMS suggested a 30% hurdle; this hurdle is somewhat higher than the sum of the onshore federal royalty rate and the highest onshore state severance tax rate (i.e., 14.2% for Montana). In response to this suggestion, Industry is amenable to a 25% hurdle for onshore and 20% for offshore. For onshore, a 25% hurdle rate is just below the 27% sum of the onshore royalty rate of 12 1/2% and the highest state severance tax rate, but well above the sum if the average severance tax rate (about 7.5%) is used. For offshore, where no state severance tax rates apply, 20% is higher than the 16 2/3% OCS royalty rate and substantially higher than the 12 1/2% rate in the deep water Gulf of Mexico. Significantly, the principal production growth area offshore is the deep water Gulf of Mexico, further obviating the need to have a volume percentage hurdle greater than the 20% recommended.

Weighted average. The MMS also asked if the comparable arm's length transactions included in the weighted average would include transactions at the lease and downstream as well. Industry believes that if volumes are sufficient to reach the minimum the weighted average should include only transactions at the lease since these best reflect value as at the lease without the need for adjustments to adjust for downstream additions of value. On the other hand, if the transactions at the lease do not reach the percent production volume hurdle, downstream transactions could be added on case-by-case basis, if agreed to by the lessee and the MMS in the course of the annual review.

C. Adjustments to Downstream Values - Transportation

The gist of Industry's recommendations on adjustments generally is that the MMS-proposed scheme for adjustments does not fully capture downstream additions to the value of production at the lease and leads to unlawfully higher royalty obligations. Significantly, these adjustments have applicability whether indexing or gross proceeds (for sales away from the lease) is employed.

For transportation, the basic difference is that the MMS' proposal is grounded on pegging transportation allowances to an insufficient cost of capital recovery estimate and operating and maintenance whereas Industry would peg transportation allowances on a commercial value of service determined in the marketplace. Although the problems with the transportation aspect of the MMS' current proposal were addressed in prior Industry comments,[5] they have not yet been addressed by the MMS. Moreover, the

[4] Rocky Mountain Oil & Gas Association, "Tax Comparison Report (Draft 9/97)."
[5] See April 1998 API comments at 7-9.

MMS-Industry exchanges at the March-April 1999 workshops makes it important to revisit the outlines of this significant issue,

1. Character of the MMS Proposal for Transportation

MMS divides transportation allowance into two distinct categories: (1) arm's-length transportation in which the transported party is not related to the party owning the line; and (2) non-arm's-length transportation which involves transportation of lease production when an affiliate of the lessee owns the pipeline. There is no controversy over arm's-length transportation since the agency generally accepts the cost paid to a non-affiliated party as the appropriate transportation allowance. The focus of controversy centers on non-arm's-length transportation for which MMS has proposed an allowance that is not related to the market value of service.

The foundation of the MMS transportation proposal for non-arm's-length transportation is that a lessee's transportation allowance should be based primarily on the recovery of the original capital investment in the oil pipeline plus operation, maintenance, and overhead expense. Capital recovery is provided by lessee selection of one of two methods: (1) depreciation of capital investment by straight line or unit of production methodology plus a fixed rate of return on the undepreciated capital, or (2) fixed rate of return on the original capital investment.

In both cases the rate of return employed is the very low Standard and Poor's BBB Bond rate. And, once the pipeline is fully depreciated, only the operating and maintenance expenses remain, which are minimal in comparison to capital costs. Pipelines may be depreciated only once and, if sold after full depreciation, cannot be depreciated again by the new owner.

To compound matters further, the MMS proposal reflects the agency's categorical rejection of FERC oil tariffs as a measure of oil allowances. FERC tariffs were expressly accepted under the 1988 regulations and have only been recently rejected by MMS because of confusion caused by several FERC decisions on the issue of whether FERC had jurisdiction over pipelines on the OCS.

This approach is flawed for the following reasons:

a. Different Valuation for the Same Oil from the Same Lease.
Under the MMS proposal, oil production from a lease owned by two lessees produced on the same day and traveling through the same pipeline owned in part by one of the co-lessees would have different royalty value merely by application of the regulation and solely as a result of one lessee owning some percentage of a line transporting the oil production. As a result, a pipeline user/non-owner (Lessee A) would be allowed to take as a deduction the commercial cost or value paid to move through the pipeline. However, the pipeline owner (Lessee B), who owns all or only a part of the pipeline would be limited to recovery of capital cost in the line. As a result, the lessee/owner would pay more royalty than the user/non-owner on the same pipeline. This would be true even if the lessee were only affiliated with the pipeline owner and paying commercial transportation rates to the affiliated pipeline owner, since the lessee

receives no revenue stream from the operations of the pipeline. Such an approach is discriminatory and puts Lessee B at a competitive disadvantage.

b. Royalty Assessed on Transportation Not on Production

Although the MMS concedes that value is to be determined at the lease, MMS' proposal focuses on values away from the lease and then uses transportation as an adjustment to net back to the lease. The downstream value which MMS uses as the starting point for value is based on the commercial value of the transportation used to get oil to the away from lease value point. For example, Platt's spot price at St. James is based on commercial transportation to the index point.

Yet when the MMS ignores the commercial value of transportation and limits transportation deductions to that downstream point to capital recovery costs for lessees owning an interest in the pipeline, the royalty is overstated and assessed not only on the oil production but on an increment of its transportation too. Under mineral leasing statutes, royalty--for all lessees-- must be based on the "value of production" and cannot lawfully include any increment of transportation.

c. Adverse Competitive Impact on Lease Sales

Royalty obligation is one of the elements entering into the calculation of expenses by bidders at OCS lease sales. However, for those bidders who own a pipeline, or are affiliated with a pipeline owner, in the Gulf of Mexico, the economics of their bid may be adversely impacted. Since mere ownership of a part of the pipeline would mean that the royalty expense must be calculated on a different and higher basis than those who do not own an interest in the pipeline, the hurdle for profitability is raised. But for those not owning the line, there is no impact. This discriminatory result could interfere with competition, adversely affecting individual bidders and the Federal Government as lessor.

d. Disincentive for OCS Exploration and Development

Under §3 of Outer Continental Shelf Lands Act (OCS Lands Act) the MMS must foster and encourage exploration and development of the OCS. Even though the development of pipeline infrastructure is a vital element in the orderly and expeditious development of the OCS, the MMS' current transportation methodology penalizes the lessee who takes the initiative and risk and makes the capital investment in pipelines. By requiring the lessee who owns an interest in the pipeline, or is affiliated with a pipeline owner, to pay a higher royalty expense than a competitor who merely later used the pipeline, the MMS creates a disincentive to install new pipelines which impacts all lessees operating in the affected area.

If the MMS transportation policy is at odds with the core of the OCS Lands Act, the exploration and development policy disincentive it creates is also incongruous with recent legislation and even more recent Administration initiatives aimed at encouraging development. It does not mesh with Congress' public policy recognizing the need for royalty relief as an incentive for certain offshore development under the Outer

Continental Deep Water Royalty Relief Act.[6] Nor does it advance elements of the Administration's Comprehensive National Energy Strategy (CNES) adopted by the Department of Energy last year which, among other things, promotes development of oil and gas resources on federal lands.

e. Discrimination on the OCS

Section 5 of the OCSLA specifically addresses pipelines and discrimination in their administration by the Interior Department as follows:

> . . .and upon the express condition that oil and gas pipelines shall transport or purchase without discrimination oil or natural gas produced from submerged lands or Outer Continental Shelf lands in the vicinity of the pipelines. . . .[7]

and later:

> (A) The pipeline must provide open and non-discriminatory access to both owner and nonowner shippers.[8]

The clear intent of these portions of the Act is to specify that movement on OCS pipelines is not to result in discrimination among shippers. Yet by requiring a reimbursement for movement of the royalty portion below that paid by other parties similarly situated, the MMS proposal for transportation plainly discriminates in violation of the spirit, if not the express terms of the Act.

f. MMS Use of Other Approaches

Over the past forty years the MMS has not always used its present capital recovery approach to determine the value of allowances for transportation. Prior to the 1988 regulation, MMS approved under the "other considerations" provisions of the regulations and lease the cost paid by third parties moving through the pipeline. This approach recognized that the measure of value for the allowance could reasonably be based on what other non-related parties paid to move through the same pipeline during the same monthly accounting period.

2. Industry Proposal

In an effort to reach closure with the MMS on the transportation adjustment issue, Industry offered a new, pragmatic recommendation at the recent workshops. Stripped to its essence, the Industry-recommended approach comprises the following:

- For arm's length transportation, the actual rate paid would be used (as the MMS proposal already provides).

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[6] Outer Continental Shelf Deep Water Royalty Relief Act, P.L. 104-58, 109 Stat.563, codified at 43 USC § 1337(a) and OCS Lands Act § 8(a).
[7] OCS Lands Act 5(e).
[8] OCS Lands Act 5(f).

- For non-arm's length transportation, where more than 20% of the pipeline volume is arm's length transportation, an annualized volume-weighted average of the arm's length rate would be used.
- Where less than 20% of the pipeline volume is non-affiliated, a rate corresponding to twice the Standard & Poor's BBB bond rate for undepreciated capital, but never less than 10%[9] of the capital cost of the original line plus operating and maintenance expenses, would be used.
- Timely issuance of subsea guidelines for the Gulf of Mexico.

See Appendix "A" at 10-13.

Industry's transportation recommendation would sidestep the jurisdictional question altogether and the FERC tariffs issues now in litigation, drawing no distinction between jurisdictional and non-jurisdictional pipelines. It would use objective, verifiable, comparable payments by non-affiliated parties as the cornerstone. It recognizes that transportation is a service for which all similarly situated parties should be treated the same to avoid discrimination and avoid interference with competition. It avoids the merchantability issue, provides certainty in administration and facilitates audits.

At the March-April 1999 MMS workshops, several questions about the Industry-recommended approach arose in three areas: the risks of pipeline operation, the cost of capital recovery, and the MMS' proposed S&P BBB bond rate itself.

Pipeline risk. MMS asked industry to further elaborate on the "risks" surrounding oil pipelines, contending that there appeared to be little risk in operating an oil pipeline after discovery of reserves. Several witnesses appeared and responded to this issue.

These witnesses established for the record that there are very real risks surrounding pipeline operation. Pipelines, especially those in the Gulf, are built at great distances for more than movement of one lease's production. Pipelines may be sized well above that needed for single lease affiliate production. This alone increases cost, but once the line is laid there is the risk of underutilization, i.e., less oil is available than the line size anticipated to operate profitably. An example of underutilization of a pipeline with increased costs and less profit was discussed.

Competitive conditions created by installation of other lines can upset planned economic premises by lowering transportation rates charged due to competition. In fact, it was demonstrated in response to MMS inquiry that there is a competitive market for transportation.

Technology challenges and changes were also cited. Technology development, especially for deepwater lines, is a very significant capital expenditure and an integral part of a resource development project. Deepwater lines cost today around one million

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9 The proposed 10% minimum, is best viewed as a management fee, appropriate even if the pipeline is fully depreciated. Absent such a fee, the owner would have limited incentives to manage the operations for the pipeline and manage the risks of continuing to operate the pipeline

dollars per mile because of the hostile conditions of water depth (i.e., extraordinary variations in temperature, pressure and undersea topography). Even today work is still underway to technically solve tie-ins below water in deeper waters of the Gulf. Overall, the MMS should take into account that there is substantial risk in operating pipelines.

Cost of capital and S&P BBB bond rate. The rate of return necessary to reasonably operate a pipeline was discussed and it was pointed out that Standard & Poor's BBB bond rate coupled with eventual zero depreciation failed to provide that return. The essential problem with the MMS methodology is that it ignores the use of higher cost equity financing. By arbitrarily assuming 100% debt financing, the MMS methodology fails to provide firms a return commensurate with the rate of return expected by investors or a return that covers the firm's cost of raising capital. Further, once a pipeline is depreciated, the firm receives no return on its investment and is merely paid a transportation rate that covers variable operating expenses. The management fee approach, used by the FERC, may be one way to rectify this problem.

Appendix **"D"** to our comments reviews the cost of capital concept and the way in which regulatory authorities (other than the MMS) typically determine the allowed return on investment in regulated industries. Our purpose here is not to suggest a particular regulatory approach for the determination of transportation rates, and certainly not to accede to a capital recovery approach in principle. Rather, the weighted average cost of capital estimates presented in the appendix show that the conventional approach for determining the cost of capital results in cost of capital estimates that exceed the estimates generated by the MMS approach. A review of estimates by others undoubtedly would show the same.

Lest there be any misunderstanding, Industry does not endorse the MMS' flawed capital recovery methodology. Industry's recommendation is really two-fold. First, if the MMS is wedded to a capital recovery approach, the MMS should adopt a rate of recovery substantial higher than the proposed Standard & Poors BBB rate. This would be more in line with the expected return required by an investor that would take into account the significant risks associated with such projects. Second, and more fundamental, the MMS should undertake a hard look at the complex transportation allowance issue and consider another workshop or a symposium. With such an opportunity, the MMS could avail itself of available expertise among other federal agencies, Industry and the public which we believe would help the MMS align its transportation allowance policies with economic realities.

D. Adjustments to Downstream Values - Quality and Location

As with adjustments for transportation, the current MMS proposal does not allow adjustments for location and quality sufficient to calculate a reasonable value of production at the lease. Specifically, the current MMS proposal:

- Relies on Form MMS-4415 that is unduly burdensome and results in the collection of information not usable for the purpose intended.

- Uses MMS-published location/quality differentials that are likely to be as much as 24 months out of date.
- Does not include all appropriate adjustments (e.g., quality adjustments between aggregation point and the lease).
- Includes as a starting point an index that in some cases may be far from reflecting the quality of crude oil being valued (e.g., some streams may have as much as a 20 degree difference in quality).
- Provides for several publications without addressing the situation publication where somewhat different spot prices for the same crude are quoted in multiple publications.

See Appendix "A" at 14.

To address these problems, industry recommended at the March-April 1999 workshops an approach with the following elements:

- Consistent with the MMS proposal, actual location/quality differentials would be used by lessees having such transactions.
- Industry and MMS would develop a uniform monthly report based on a combination of actual location/quality differentials and location/quality differentials calculated from gross proceeds transactions. This report would represent a methodology that reflects value at the lease versus index price normalized to index gravity. Reported location/quality differentials would be aggregated by the MMS on a periodic basis, at least quarterly, for use by companies without alternative means to value non-arm's length transactions.

See Appendix "A" at 18.

Industry also suggests that in developing the form, the MMS:

- specify one publication per crude;[10]
- use nationwide the nearest index point with like quality; and.
- allow adequate adjustments for transportation.

Such an approach offers several distinct advantages. It uses more current data to better reflect the dynamic crude oil market and arrives at a more accurate value of production at the lease. It uses information on crude oil quality at the lease based on transactions that are auditable. It would be less costly to administer than Form MMS-4415 because it would not require the collection of unnecessary, difficult to assimilate information. Finally, the information collected is not proprietary and would be available to industry and the MMS. See Appendix "A" at 16.

[10] As an alternative, the MMS could establish a seriatim list for each crude, identifying more than one publication but specifying their order of use depending on availability of publication.

E. Adjustments for Downstream Values – Midstream Activities

In addition to the transportation, quality and location adjustments described above, further adjustments to a market center index may be necessary to accurately calculate the value of production at the lease. These adjustments are for midstream costs that are incurred whenever crude oil is sold away from the lease market, at some downstream point such as the market center index point.

Many of the midstream costs are components of an overall transportation cost, such as scheduling of transportation volumes, pipeline fill, pipeline loss allowances, risk of transport failure, risk of pipeline spill, oil distribution fees, scheduling of storage volumes, maintaining inventory, and the time value of money associated with the delivery of volumes. At the March 25, 1999 workshop in Albuquerque, MMS acknowledged that costs of transportation-related midstream activities should be allowed as an adjustment. Industry requests that MMS, having acknowledged the propriety of such adjustments in the workshops, expressly allow for such adjustments in the final rule.

There are other non-transportation-related costs of midstream functions that help account for the difference in spot market center indices and value of production at the lease. These midstream functions include securing division orders, disbursing production proceeds, complying with regulatory and reporting requirements, aggregating supplies, staffing and salaries, and office facilities and equipment. If MMS does not permit all appropriate adjustments, it would be assessing royalty on the value of those midstream functions and would be unlawfully determining the market value at the lease, since royalty is due on the "value of production."

MMS has also recognized that other midstream adjustments from index may be taken into account. In its own contract with small refiners under the royalty in kind program, the MMS admits to the "arm's length negotiation" of a flat $0.35 per barrel adjustment off index for production delivered to the small refiners at the market center (where transportation, quality and location differentials would not be at issue). It would logically follow that further adjustments which include the cost of midstream functions would be necessary to arrive at the value of production at the lease. Furthermore, 43 USC 1353 (b)(2) requires that federal production taken in kind and delivered to small refiners shall be at "fair market value." This negotiated adjustment in its contract with small refiners is recognition by MMS that spot index prices do not represent "fair market value" even at the market center.

F. No Second-Guessing

At its core, the industry recommendation would emphasize that the lessee deserves a presumption in favor of good faith where a lessee enters into an arm's length transaction. The mere existence of a higher price in another transaction should not suffice to have the transaction deemed non-arm's length or to disallow the price received as the value for royalty purposes. <u>See</u> Appendix "**A**" at 19-20.

Underlying this recommendation is the fact that economic interest drives the lessee to seek the highest price wherever possible; after all the lessee's share is 5/6 offshore and 7/8 onshore whereas the lessor's royalty share is 1/6 offshore and 1/8 onshore. Moreover, a presumption of good faith would not, of course, shield lessees from audit and would not be license for misconduct or fraud. Lessees operating in good faith simply need a reasonable threshold before their normal business transactions can be set aside.

In the course of the workshops, specific regulatory language was developed to strike a balance on this important issue, drawing on industry proposals and the earlier comments of the State of California. See Appendix " **B**"; see also Appendix "**A**" at 21-22.

F. Binding Determinations

The gist of industry's recommendation is that lessees trying to comply with MMS valuation regulations need an explicit process by which they can obtain timely MMS determinations of valuation methodology that can be relied on for satisfying royalty obligations.

In earlier comments, API alluded to the IRS' regulations for private letter rulings[11] but at the recent workshops, Industry offered a specific recommendation having several specific features:

- Limited to the specific facts presented for a specific property (i.e., no hypothetical cases);
- No precedential effect;
- Requires MMS determinations within a prescribed time period (i.e., 180 days);
- Prescribes default in absence of MMS action (i.e., lessee could rely on proposed methodology until MMS decides otherwise); and,
- Could be revoked prospectively (i.e., lessee would have determination it could rely on until MMS changed its mind; prospective MMS change would involve no revision of records and payments and would be subject to challenge).

See Appendix "**A**" at 24-27.

As the MMS knows, several federal agencies have procedures in place to generate case-by-case rulings to assist regulated entities to comply with agency regulations.[12] For example, United States Customs Service regulations contemplate the issuance of a variety of rulings at the request of a regulated party. The Customs Service regulations make the rulings inapplicable to hypothetical questions,[13] limit the rulings to actual prospective transactions described by specific facts,[14] and permit the applicant to

[11] See API April 1998 comments at 11-12.
[12] *See, e.g.*, Internal Revenue Service regulations at 26 CFR 601; Department of Treasury regulations at 17 CFR § 400.2; Customs Service regulations at 19 CFR Part 177; Department of Energy regulations at 10 CFR Parts 205 and 490; Contract Disputes Act, 48 CFR § 33.211; Security and Exchange Commission, 17 CFR §140.99 (a)(2); Department of Justice, 28 § 80; Government Ethics Standard of Ethical Standards of Ethical Conduct, 5 CFR Part 2635.
[13] 19 CFR § 177.7.
[14] 19 CFR § 177.2(b).

propose a particular ruling. [15] Although the Customs Service rulings may be narrowly limited in application,[16] they are binding upon issuance,[17] and are subject to administrative appeal.[18] The Customs Service rulings can be revoked or modified but, so changed,[19] do not apply retroactively, provided several reasonable conditions are met (e.g., no misstatement or omission of relevant facts, good faith reliance).[20]

In addition, several agency regulations prescribe a period of at least presumptive length for agency disposition of the ruling request.[21] This is especially significant for lessees who are subject to fines for failure to make accurate and monthly royalty payments. Moreover, lessees are situated quite differently from most other regulated parties who seek rulings from other agencies, because crude oil production is not an isolated event but a continuing process where any delays in valuation could necessitate substantial retroactive changes in records and royalty payments which are costly to perform.

During the March-April 1999 workshops, certain questions arose in connection with the problems with non-binding determinations: participation by states in the process; the difficulty of arriving at determinations; the lack of MMS resources.

Problems with non-binding determinations. At the April 7, 1999 workshop, Industry representatives explained, non-binding determinations pose a dilemma for a lessee. If the MMS determination is adverse, but not binding, the lessee has no recourse except to accede to it or ignore it and face the prospect of an order to pay, possible penalties, and potentially allegations of False Claims Act violations. Even if the determination is favorable, its non-binding character in no way constrains auditors from later issuing demands leading to the same consequences. Thus, future non-binding determinations would be of dubious value, but binding determinations would be of great value.

State participation. Industry is unaware of any agency ruling procedure that expressly provides for participation by other parties such as the states. However, Industry believes such provisions are unnecessary. Industry suggests instead that the MMS adopt procedures comparable to Department of Energy regulations that require that interpretive rulings be placed in a public file.[22]

MMS resources and difficulty. At the April 7, 1999 workshop, the MMS voiced reservations about the establishment of an explicit process beyond the proposal that the

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[15] 19 CFR § 177.2(b)(6).
[16] 19 CFR § 177.9(b)(3).
[17] 19 CFR § 177.9(a).
[18] 19 CFR § 177.2(b)(2)(B).
[19] 19 CFR § 177.9(a).
[20] 19 CFR § 177.9(d)(2). *See also* Department of Energy regulations at 10 §490.5(h)(1) specifying that a person relying on an interpretive ruling shall not be "subject to an enforcement action for civil penalties or criminal fines for actions taken in reliance thereon. . . ."
[21] Contract Disputes Act decisions at 48 CFR sec33.211 (60 days); Department of Justice Foreign Corrupt Practices Act opinions at 28 CFR § 80.8 (30 days); Department of Justice Foreign Agents Registration Act opinions at 28 CFR §5(i).
[22] See DOE regulations at 10 CFR §490.5(k).

Assistant Secretary or his delegate be empowered to issue binding determinations.[23] Underlying its reservations, the MMS said that necessarily required substantial agency involvement, consideration of comparable situations, and staff resources well beyond the existing complement.

Without trivializing MMS' resource and decision making concerns, Industry would only observe that lessees have the obligation to report production and pay royalties within 30 days, and face imposition of interest, penalties, and even allegations of False Claims Act violations, if strict compliance with the MMS' complex valuation regulations--often determined through audits years later--does not occur. Industry does not quarrel with the strict compliance, only that the MMS is best situated to make the determinations lessees need to rely on. To the extent there is a staff resource problem, we submit that this is attributable to the inherent complexity of fair valuation regulations which could be eliminated through adoption of royalty-in-kind in lieu of valuation. However, if the MMS needs additional resources to do its job, Industry urges the MMS to raise this during the congressional appropriations process.

Industry simply urges the MMS to craft its own procedures, tailored to deal with the realities of oil and gas production and the associated royalty reporting and payment obligations. Royalty determinations so obtained would, of course, not be substitutes for audits but would, we believe, lead to far fewer controversies, appeals and litigation, all of which consume lessee and government time and dollars.

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<u>**List of Appendices**</u>

Appendix A: Compilation of Joint Industry Recommendations Offered at March 23, March 24 and April 6-7, 1999, MMS Workshops on Crude Oil Valuation Rulemaking

Appendix B: Additional Industry Recommendation on Second-Guessing Issue Developed at April 6-7, 1999 MMS Workshop on Federal Crude Oil Valuation Rulemaking

Appendix C: ABC Company's December 1998 Location/Quality Differential for Federal Crudes

Appendix D: The Cost of Capital vs. the Return on Investment Allowed by the MMS

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[23] *See* 64 FR 12267,12269 (March 12, 1999), citing the letter of the Assistant Secretary, Land and Minerals Management, to Members of Congress, dated August 31, 1998.

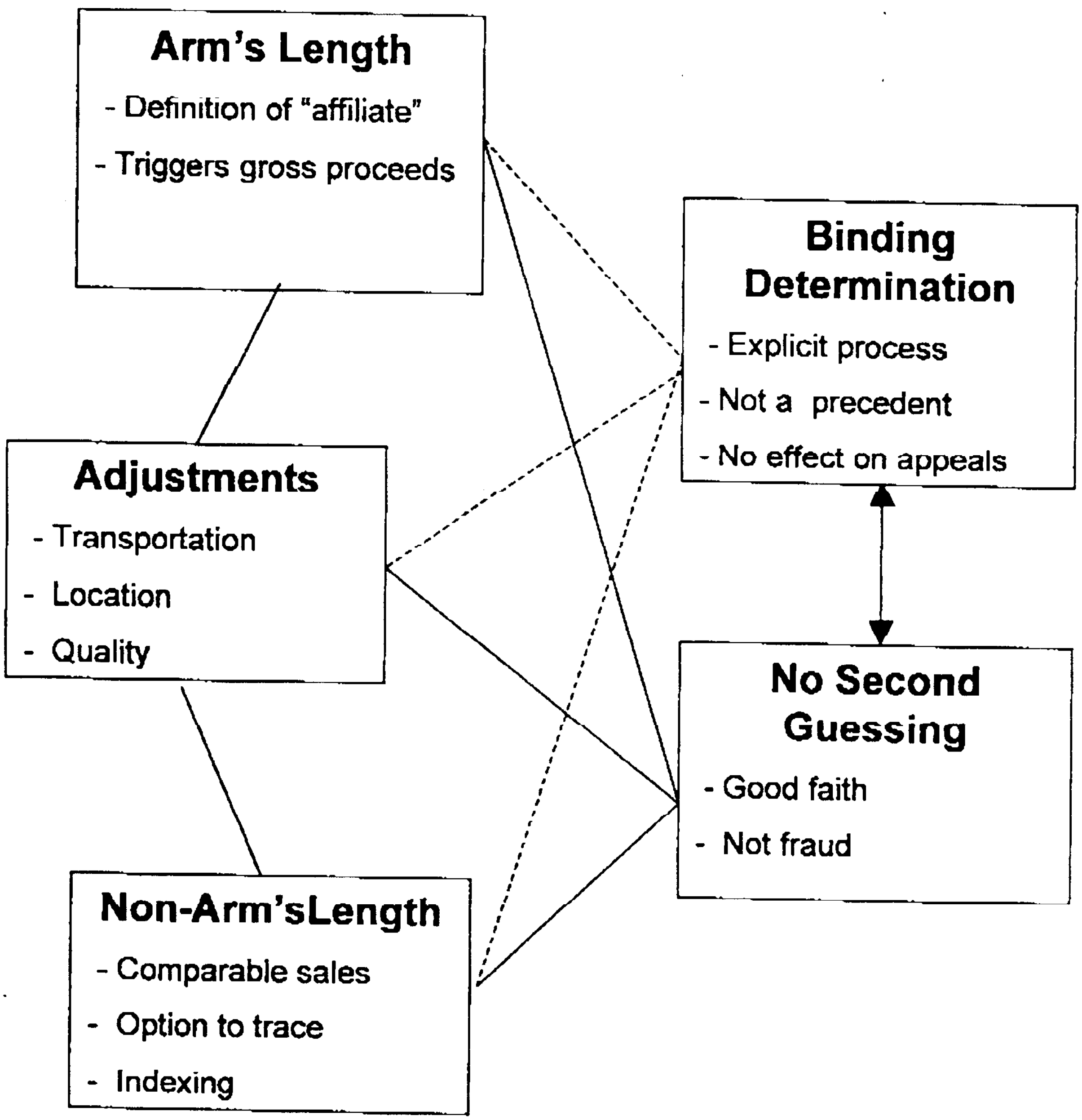
Appendix A

Compilation of Joint Industry Recommendations Offered at March 23, March 24 and April 6-7, 1999 MMS Workshops on Federal Crude Oil Valuation Rulemaking

Appendix A

Compilation of Joint Industry Recommendations Offered at March 23, March 24 and April 6-7, 1999 MMS Workshops on Federal Crude Oil Valuation Rulemaking

Oil Valuation Overview



DEFINITION OF AFFILIATE
BACKGROUND

- Current language outlines arm's length versus non-arm's length
- Includes presumption of control/non-control without guidelines on how to rebut
- MMS has agreed to accept current definition of control/non-control to define "affiliate"
- Proposed rule uses definition more broadly than current rule

DEFINITION OF AFFILIATE
INDUSTRY PROPOSAL

Sets forth generally applicable guidelines for rebutting presumption in the following manner:

- If affiliated entity can take any relevant action without affirmative vote of lessee, then no control
- If lessee is not general partner of a partnership, then no control
- If lessee is a natural person not related within the fourth degree to the affiliated natural person, then no control
- If lessee's directors on board of affiliated company cannot block any relevant action of affiliated company, then no control through interlocking directorates
- Use same percentages as existing regulations

DEFINITION OF AFFILIATE
MERITS OF INDUSTRY PROPOSAL

- Implements MMS' stated goal of providing guidelines using current control/non-control guidelines with same percentages
- Establishes objective guidelines not existing in current regulations
- Add clarity and certainty to existing regulations

COMPARABLE SALES MODEL
BACKGROUND

- Goal is **value of production at the lease**
- Builds on MMS comparable sales benchmark in the Rockies
- Builds on recognized concept of arms length value of similar production
- Intrinsically simpler than netback

COMPARABLE SALES MODEL
COMPONENTS OF MODEL

- Premised on third party arm's length transactions at the
- At least 20% of production must be sold / purchased arms length within comparable production area
- Objective data for validation is maintained by lessee
- Minimum number of bids (3) for bid outs
- Value based on weighted average prices of third party transactions
- Adjustments for quality and transportation as necessary
- Annual review with MMS

COMPARABLE SALES MODEL
MERITS

- Resolves MMS perceived concerns with comparable sales/purchase as incorporated in current benchmarks
- Captures the unique values at individual leases (preferred point for lessor and lessee)
- Avoids complexity of calculating differentials between lease and market center
- Used by states and MMS in RIK programs
- Builds on MMS limited proposal in Rockies
- Solves audit issues through simplified procedures

COMPARABLE SALES MODEL
CONCESSIONS

- Stricter qualifications for participation addresses MMS' past criticisms
- Increases required lessee record keeping
- Increased percentage to risk company production over royalty burden
- Minimum number of bids required to demonstrate active market

Example of a Comparable Lease Sales Program

Produced from Field	1050 Bbls
Portion Sold	250 Bbls
Weighted Average Price of Portion Sold	$3000
Average Price Per Bbl Sold	$12 / Bbl
Value of Portion Not Sold	$9600

TRANSPORTATION
BACKGROUND

History & Impact

- Recovery of capital and O & M
- 1988 Regs Tariff was compromise
- Dispute over tariffs
- Rate of return inadequate

TRANSPORTATION **PROPOSAL**

Service is provided – value of service

- Avoids jurisdictional issue
- Use arm's length comparables as cornerstone
- For arm's length use actual rate paid
- For non-arm's length use dual approach
  - ➢ More than 20 % non-affiliate – annualized volume weighted average rate paid
  - ➢ Less than 20% non-affiliate use modified MMS approach:
    - 2X triple B
    - Never less than 10% capital cost of original line + O&M

TRANSPORTATION
SUBSEA

- Industry proposal previously provided
- Status of subsea transportation guidelines?

TRANSPORTATION
MERITS OF INDUSTRY PROPOSAL

- Sets aside tariff jurisdictional dispute
- Recognizes that transportation is a service
- Uses comparability to validate – good for product value – good for transportation
- Focus on non-arm's length sale and concedes lower rate for non-arm's length
- Treats all parties similarly situated the same
- Certainty & ease for audit
- Provides for Subsea guidelines
- Avoids merchantability issue
- Important element of fair netback

ADJUSTMENTS OFF DOWNSTREAM VALUES: LOCATION/QUALITY DIFFERENTIALS

BACKGROUND

- Goal is value of **production at the lease**
- Current MMS proposal does not adequately reflect adjustments off index or downstream value to approximate lease value
- Form MMS-4415 is administratively burdensome; information collected may not be useable for purpose intended
- MMS-published differentials would be as much as 24 months out of date
- Current MMS proposal for California uses a starting point (ANS) that is vastly dissimilar from most California crudes even though other published market prices exist that more closely match federal crude quality
- MMS proposal does not allow for all appropriate adjustments such as allowing an adjustment for quality between "aggregation point" and lease

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ADJUSTMENTS OFF DOWNSTREAM VALUES: LOCATION/QUALITY DIFFERENTIALS
INDUSTRY PROPOSAL

- Where it can be established that there are no arm's length or comparable sales, can use an netback methodology to approximate lease value
- Uses actual location / quality differentials where available
- Industry and MMS to develop report or contemporaneous tables by region incorporating differentials reflective of recent market conditions
- Differentials to be applied as an adjustment to appropriate index
- Differentials based on actual crude quality at the lease as compared to downstream quality

ADJUSTMENTS OFF DOWNSTREAM VALUES: LOCATION/QUALITY DIFFERENTIALS
MERITS OF INDUSTRY PROPOSAL

- Use of more current data makes differentials more reflective of dynamic market
- Uses actual crude quality data at the lease
- Information is not proprietary as reported and is auditable
- Replaces Form 4415 with a more workable method
- Methodology is improvement over quality adjustment to market center indices which MMS appears to accept

ADJUSTMENTS OFF DOWNSTREAM VALUES: LOCATION/QUALITY DIFFERENTIALS
CONCESSIONS

- Specifies adjustments (e.g., transportation and location/quality differentials) for use with an index netback calculation method to better approximate lease value
- Proposal makes a prospective netback adjustment method less objectionable to industry as an option when there are no arm's length sales or comparable sales

Basic Formula

Formula	Comments
Downstream Sales or Appropriate Market Center Index	Nearest Index Point with like quality (1)
+/- Gravity	Use actual; if no actual, use table such as Gravcap in GOM
+/- Sulfur	Use actual; if no actual, use prevailing practice such as Gravcap in GOM
- Transportation	See Proposed Transportation Adjustments on Page Eight
+/- Location Differential, includes: - Midstream costs +/- Spot to Term +/- Location	Options include: (1) Use buy/sells on a portion of a company's crude as a comparable for crude without buy/sell and not sold (2) Create a "table" adjustment based on internal information on a company by company basis w/ some actual transactions (3) Compile #1 and/or #2 and turn in on a current basis to MMS; MMS consolidate from multiple reporters and publish
Calculated Approximate Lease Value	

(1) For Index: One publication per crude or a seriatum list per crude -- use first, if no longer published, use second, third, etc.) should be declared by MMS. Starting point for California would be Kern River or other "nearest index point with *like* quality."

NO SECOND-GUESSING
BACKGROUND

- Rule appears to contain several opportunities where language can be made more certain for both the lessor and lessee
- Industry and MMS concur on stated objective of certainty for arm's length sellers
- Appears to be some misunderstanding between MMS and industry over whether or not to include no second guessing language

NO SECOND-GUESSING
BACKGROUND

- Rule appears to contain several opportunities where language can be made more certain for both the lessor and lessee
- Industry and MMS concur on stated objective of certainty for arm's length sellers
- Appears to be some misunderstanding between MMS and industry over whether or not to include no second guessing language

NO SECOND-GUESSING
INDUSTRY PROPOSAL

1. Further define gross proceeds as those accruing to lessee
2. Move any references to non-arm's length sales from gross proceeds section to the non-arm's length section
3. Eliminate the reference to examples of services performed at no cost, e.g. marketing
4. Evaluation of breach of duty will be comprised of the following:
   (a) whether or not the total consideration was actually paid, and/or,
   (b) a comparison of other comparable sales
5. Place the options to either value in accordance with non arm's length provisions or upon first arm's length transaction beyond an exchange or affiliate transaction in non arm's length section
6. Parallel current gas valuation language beginning "You must base value..."

NO SECOND-GUESSING
MERITS OF PROPOSAL

- Preserves debate over duty to market
- Provide guidance for evaluation of gross proceeds that both lessee and lessor can understand
- Greater certainty and clarity
- Restricts MMS' broad ability to audit and interpret

BINDING DETERMINATION
BACKGROUND

- Timely Valuation determinations are needed to reasonably conduct business
- MMS and Industry agree that a binding determination process should be included in new rule
- Need a process to implement

BINDING DETERMINATION
INDUSTRY PROPOSAL

- Lessee proposes valuation method for a specific property
- Determinations on a case-by-case basis
- Determination has no precedential value beyond the facts in request
- MMS given 180 days to decide on Lessee's proposal; decision subject to existing appeals procedures
- Subject to later adjustment, the Lessee pays royalty on the proposed method until MMS renders a decision
- Failure to respond within the 180-day period results in automatic adoption of the Lessee's proposed valuation.
- MMS may still act after 180 days but change prospective only

BINDING DETERMINATION
MERITS OF INDUSTRY PROPOSAL

- Industry proposal set forth above resolves an issue acceptable to both MMS and lessees
- Provides timely mechanism to conduct business with certainty
- Eliminates future disputes on audit – simplifies administration
- Builds on MMS 1988 regulation authorizing a lessee to request valuation determination

BINDING DETERMINATION

(a) A lessee or delegee may request that DOI approve a specific valuation methodology that is consistent with applicable statutes and regulations. In its request, the lessee or delegee shall submit all pertinent information respecting the disposition of production subject to the proposal.

(b) If DOI concludes that the lessee or delegee failed to provide all of the information required under paragraph (a), DOI shall, within forty-five (45) days of receipt of the valuation proposal, request that the lessee or delegee provide the omitted information.

(c) DOI shall act on the requested valuation proposal prior to the latter of (i) 180 days after the lessee's or delegee's submission of the proposal or (ii) 135 days after receipt of the additional information submitted by the lessee pursuant to paragraph (b). Any order issued pursuant to this paragraph (c) shall be applicable only to the disposition of production described in the lessee's or delegee's valuation proposal and shall not otherwise have precedential value. In acting on the valuation proposal, DOI shall choose the valuation methodology most applicable under applicable laws and regulations to the disposition of production described in the proposal.

(d) A lessee or delegee who submits a proposal under paragraph (a) may pay royalties pursuant to the methodology outlined in the proposal until and unless DOI rejects or modifies that proposal. In the event that DOI, prior to the applicable deadline set forth in paragraph (c), prescribes a modified or different methodology which results in additional amounts being due for the period during which royalties were paid pursuant to the proposal, the lessee or delegee shall pay the additional amounts due with interest calculated pursuant to 30 U.S.C. § 1721(a).

(e) A lessee or delegee aggrieved by an order issued pursuant to paragraph (c) may appeal the decision under the procedures provided under 30 U.S.C. § 1724(h)(1). If the order is not appealed within thirty (30) days of its receipt by the lessee or delegee and if the lessee or delegee complies with such order, the lessee or delegee shall be deemed to have fulfilled its royalty payment obligations with respect to the disposition of production subject to such order for all periods between the date of the lessee's or delegee's submission of its request and the date, if any, that the Department revokes or modifies the order.

(f) If MMS fails to act within the applicable period prescribed by paragraph (c) and if the lessee or delegee utilizes the methodology set forth in its proposal as the basis for the payment of its royalties on the disposition of production described in the proposal, then the lessee or delegee shall be deemed to have fulfilled its royalty payment obligations with respect to such disposition of production for the period between the date of the submission of the proposal and the date when DOI orders the lessee or delegee to adhere to a different or modified methodology.

(g) The Secretary of Interior or Assistant Secretary for Land and Minerals Management may act on the requested valuation proposal pursuant to paragraph (c), in which event any such timely issued order will constitute final agency action, subject to judicial appeal by the lessee or delegee.

(h) Nothing contained herein shall limit the authority of the Secretary or Assistant Secretary for Lands and Minerals Management to enter into any settlement agreement with a lessee or delegee establishing a valuation methodology which binds the lessee or delegee and DOI.

Appendix B

Additional Industry Recommendation on Second-Guessing Issue Developed at April 6-7, 1999 Workshop

Additional Industry Recommendation on Second-Guessing Issue
Developed at April 6-7, 1999 Workshop on Federal Crude Oil Valuation

§206.101

- Retain the current definition of "gross proceeds."

§206.102

- Replace the term "seller" with "lessee."

- Move reference to non-arm's length sales to non-arm's length sales section.

- Provide option to trace through affiliate resale or use other non-arm's length method in non-arm's length section.

- Rewrite §206.102(c) as follows:

  You must value the oil under section 206.103 if MMS determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

  (i) misconduct by or between the parties to the arm's length contract; or

  (ii) breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

  MMS shall accept arm's length transactions entered into by the lessee as the appropriate basis for federal royalty payments even though that value may not be the same as spot prices, NYMEX prices, or other index prices, or other prices received in other good faith arm's length transactions, provided that the value for royalty payments is the total consideration the lessee actually received at the lease for oil produced from federal oil and gas leases which has been placed in marketable condition, less applicable allowances.

- Add preamble language. to wit:

  The MMS will not evaluate the method used by the lessee to market its oil when determining whether the lessee marketed in "good faith." For example, if a lessee decides to sell its oil at the wellhead instead of selling it at a downstream point, the mere fact that the lessee receives a lower price than he may have received at another point of sale, absent other factors indicating fraud, illegality or bad faith, would not indicate lack of good faith by the lessee, and would not be a circumstance that would require royalty adjustments in any potential future audits.

§206(d)(3)

- Rewrite §206(d)(3) as follows:

Value must be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments must be in writing and signed by all parties to an arm's length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract, but the purchaser refuses, and the lessee takes documented reasonable measures, to force purchaser compliance, the lessee will owe no additional royalties unless monies or consideration resulting from the price increase or additional benefits are received. This paragraph will not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of oil.

§206.106

- Revise §206.106 to read as follows:

The lessee is required to place oil in marketable condition at no cost to the lessor unless otherwise provided in the lease agreement or this section. When the value of hydrocarbons is determined by gross proceeds, the gross proceeds will be increased to the same extent that the gross proceeds are reduced by the purchaser, or other party, providing certain services to the lessee when the cost of these services are ordinarily part of the lessee's responsibility to place the oil in marketable condition.

Appendix C

ABC Company's December 1998 Location/Quality Differential for Federal Crudes

ABC Company's December 1998 Location/Quality Differential for Federal Crudes

The following table depicts the differential that ABC Company did or would have used in transactions involving Federal crudes relative to various market center index crudes.

Index Crude - WTI at Cushing as measured by the average of NYMEX quotes during the month of December, 1998 - assumes 40º API gravity.

Crude	Delivery point	Location/Quality vs index	Other Quality Adjustments
NM, WT, Ok intermediate sweet crudes	@ lease	($0.66)	Gravity adjustment table.
Wyo Sweet	@ lease	($1 66)	Gravity adjustment table.
Wyo SW Sweet	@ lease	$0.14	Gravity adjustment table.
ND Sweet	@ lease	($2.61)	Gravity adjustment table.
Utah 4 Corners	@ lease	($0.91)	Gravity adjustment table.

Index Crude - WTS at Midland as measured by the average of Platts quotes during the month of December, 1998 - assumes 34º API gravity.

Crude	Delivery point	Location/Quality vs index	Other Quality Adjustments
WT, NM, Ok sour crudes	@ lease	($0.61)	Gravity adjustment table.
WT Yates	@ lease	($0.36)	Gravity adjustment table.
Wyo Asph sour	@ lease	($0.71)	Gravity adjustment table.

Index Crude - LLS at St. James as measured by the average of Platts quotes during the month of December, 1998 - assumes 35º API gravity.

Crude	Delivery point	Location/Quality vs index	Other Quality Adjustments
SoLa Sweet	1st on-shore point	($0.31)	Gravity adjustment table.
SoLa Sour	1st on-shore point	($0.94)	Gravity adjustment table.

Index Crude - Kern River delivered into the pipeline as measured by the average of Platts quotes during the month of December, 1998 - assumes gravity of 13º API

Crude	Delivery point	Location/Quality vs index	Other Quality Adjustments
SJV	@ lease	($X)/B	Gravity adjustment table.
Off-shore Calif.	from lease into AAPL 20ºAPI gravity 5% sulphur	($Y)/B	Gravity @ x/º Sulphur @ y/SB

Appendix D

The Cost of Capital vs. the Return on Investment Allowed by the MMS

The Cost of Capital vs. the Return on Investment Allowed by the MMS

Introduction

The cost of capital is typically represented as the weighted average cost of a firm's equity and debt. Thus, a firm's existing capital structure (which comprises the respective proportions of its issued debt and equity), as well as its cost of issuing additional debt and equity, determine its overall cost of raising capital.

This appendix explains the cost of capital concept and how the cost of capital is calculated. Next, the procedure used by the MMS for determining the return on invested capital is reviewed. The MMS provides pipelines a return on their undepreciated investment equal the return on BBB bonds. A comparison of the petroleum industry's cost of capital, adjusted for taxes, highlights the fact that the current MMS methodology restricts returns on invested capital to rates that are below the oil and gas industry's weighted average cost of capital (WACC). Finally, the problem of depreciation and the concept of a management or service fee, used to compensate owners of fully depreciated pipelines, are discussed.

The Cost of Capital

In general terms, the cost of capital is the minimum rate of return necessary to attract capital for investment. It also can be defined as the expected rate of return prevailing in capital markets on alternative investments of equivalent risk. Firms invest in projects expecting to earn a rate of return that equals or exceeds their cost of capital. If firms cannot earn at least enough to cover their variable operating costs *and* their cost of capital, they will not be willing to raise funds for project investments. A firm that fails to earn a return that at least covers its cost of capital and variable operating costs is not viable in the long run.

In addition to keeping the above economic principles in mind, legal rules require regulators to carefully evaluate a firm's cost of capital. [1] The traditional rationale for cost-of-service rate regulation (e.g., by the FERC and state public utility commissions) is that the regulated company is a monopolist. Since competitive forces are not considered fully operative, cost of service regulation seeks to generate a rate of return that is "reasonable", i.e., one that would be earned if competition reigned. Thus, regulatory agencies have long adhered to the requirements laid out in leading court cases. [2] Cost-of-service methodologies also typically allowed firms to charge rates that covered variable operating costs.

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[1] Pipelines transporting royalty production should not be treated as if they are public utilities.
[2] See *Bluefield Water Works v. P.S.C.*, U.S. 679 (1923); *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

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The Weighted Average Cost of Capital

Firms typically raise capital by issuing debt and equity. The cost of issuing debt instruments normally is lower than issuing equity. Given this relationship, one might ask why firms ever resort to equity financing. Both debt and equity are issued because a firm's access to debt markets (i.e., its "debt capacity") is limited by the fact that investors perceive an excessive debt level as risky. From the investors's perspective, one advantage of purchasing a debt instrument over equity is that the firm is obligated to pay off debt holders before equity holders should bankruptcy ensue. If the firm is financed entirely by debt, the ability of debt holders to recover their investment if bankruptcy occurs would be weakened. For this reason, there is a limit on a firm's reliance on debt for financing.

The cost of capital is properly calculated as the weighted average of the various types of funds used by a firm to raise funds, *regardless of the specific financing used by the firm to fund a particular project.* Suppose debt alone was earmarked to finance a specific project. The cost of debt financing allocated by the firm to the project does not reflect the cost of capital because the firm has "used up" part of its debt capacity and will be forced to direct equity capital to other projects.

A General Approach for Determining the Cost of Capital

One recognized methodology for measuring a firm's (or an industry's) cost of capital is based on the weighted average of debt and equity costs.[3] The weighted cost of capital, k_w, is given by the expression:

$$(1) \qquad k_w = w_d k_d (1-t) + w_e k_e$$

where w_d and w_e represent the respective proportions of debt and equity; k_d and k_e represent the cost of debt and equity; and t is the corporate tax rate. The cost of debt for a firm or industry is represented by the return on bonds that investors require, given the perceived riskiness of the firm or industry. For example, the return offered on a Standard & Poor's BBB rated corporate bond is sometimes used as a measure of the cost of debt (as opposed to the total cost of capital) for an average firm.[4]

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[3]Most finance texts present the basic model described here. See, for example, Eugene F. Brigham, *Financial Management: Theory and Practice, 4th ed.* Dryden Press, 1985; Richard Brealey and Stewart Myers, *Principles of Corporate Finance, 2nd ed.*,1984; and Kolbe et. al., [1984].

[4] Determining the rate to use is complicated by a bond's date of maturity. As the date of maturity extends into the future, the return on a bond of a given grade usually increases since investors perceive increased financial and business risk the longer it is before the bond matures.

Determining the Cost of Equity Capital

The Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow Model (DCF) are two widely used methods for estimating the cost of equity capital, although there are others. The CAPM model takes into account the "systematic" financial risk associated with the firm's stock. Systematic risk is a measure of the extent to which changes in the returns from holding a firm's stock is correlated with changes in the returns from holding a portfolio that reflects the entire stock market. Systematic risk is referred to as a firm's Beta. Most empirical measures of Betas are based on movements in stock prices over the previous 60 months. The cost of equity is given by the expression:

$$(2) \quad k_e = R_f + \beta(k_m - R_f)$$

where R_f is the return offered by a risk free investment (e.g., a Treasury Bill), β is the firm's beta, and k_m is the return offered by investing in a portfolio representative of the entire market. The term in parentheses, the difference between k_m and R_f, is a measure of the long-term risk premium afforded by investing in equities.

In contrast to the backward looking CAPM, the DCF model is forward looking. The DCF methodology estimates the rate of return on a stock that investors expect (and that the firm must attempt to provide) by looking at how the dividend yield is expected to grow. In its basic form, the DCF model can be expressed as:

$$(3) \quad k_e = D/P + g$$

where D is expected dividends; P is the current price of the firm's stock; and g is the rate at which dividends are expected to grow in the future.

The MMS Methodology for Determining Transportation Charges

When a lessee providing transportation for royalty production has a non-arm's-length contract or no contract, the transportation charge is based on the lessee's "reasonable actual costs". The MMS recognizes operating and maintenance (O&M) costs. These costs include tangible variable costs such as labor, fuel, utilities, rent, and ad valorem taxes (but not income taxes), as well as expenses related to operations supervision and engineering. Overhead expenses directly attributable to and allocable to the operation and maintenance of the pipeline also are allowed.

With respect to the fixed investment in the pipeline, the lessee can elect to include annual depreciation plus a return on undepreciated investment *or* it can include a cost based on the undepreciated portion of its investment multiplied by a rate of return equal to the yield on BBB bonds. Under the MMS regulations, it is unclear whether the lessee can earn a return on the capital invested during the period prior to construction. Regulatory agencies permit such a return to be recovered once the facility is placed into service through use of an "Allowance for Funds Used During Construction". As the pipeline ages, the transportation rate for royalty production falls and finally approaches a floor determined by variable O&M costs. The MMS rationale is that it doesn't want "to pay for a pipeline twice".

The notion that the MMS is "paying" for the pipeline makes little economic sense since most firms use debt and equity to raise capital. As was explained above, the cost of capital takes into account the higher cost of equity as well as the cost of debt. Further, there is no rationale for ignoring the cost of capital used during the construction phase. Thus, the MMS methodology results in a transportation charge on royalty production that is below the real cost of providing transportation services. In effect, the MMS is assessing a royalty on transportation as well as production.

Comparing Estimates of the Petroleum Industry's Weighted Cost of Capital with the MMS' Currently Allowed Return on Invested Capital

In comparing data on the cost of capital, income taxes must be taken into account. The cost of equity capital is the return that investors require if they are to invest in an enterprise. For the corporation to pay dividends and offer the return, *as calculated above*, to investors, they must earn an even higher rate on invested capital since they must first pay corporate income taxes before they can pay dividends. Thus, the actual rate of return that must earned on investment is higher than what the third party surveys set forth as the cost of capital (i.e., these surveys report after tax returns). For example, if the corporate income tax rate is 35%, then, as an approximation, an after tax return on equity of 12% is equivalent to a pretax return of 16.2%.

Rather than express the required rate of return on equity in pretax terms, regulatory commissions, when determining the allowed return using the CAPM or DCF methodologies, allow the firm to treat income taxes as a cost of operation. This convention compensates firms for income taxes, but it masks the fact that firms must earn more than what is implied by the CAPM or DCF methodologies. Since the MMS does not permit firms to treat income taxes as an expense of operation, any return based on an estimated cost of capital must be adjusted upward to compensate firms for income tax effects.

Numerous organizations (academic, investment firms, and investor newsletters) estimate the cost of capital for individual companies and for industry groups. Most estimates are proprietary and cannot be reproduced. However, in broad terms, current estimates of the petroleum industry's weighted average cost of capital range typically range from 9.5% to 11.6%. It should be recognized that the cost of capital for individual companies, depending on their size and borrowing capacity, could fall outside this range. Further, the cost of capital can vary over time in response to changing economic conditions as well as individual company circumstances.

As just explained, these estimates represent after tax calculations. Because the MMS does not allow firms to treat income taxes as an expense, these estimates must be adjusted upward to generate equivalent pretax returns that the firm must earn to meet investor expectations, as indicated by the above range of estimates. Assuming an average corporate tax rate of 35%, the industry's effective cost of capital (for pipelines subject to the MMS rate methodology) ranges from 12.8% to 15.7%.

In contrast, the return on BBB bonds averaged 7.2% in 1998 and is averaging 7.4% this year.[5] Thus, there is at present a gap of some 5.4 to 8.3 percentage points between what the MMS allows on pipeline investment and a rate that is similar to the industry's actual cost of capital.

The Problem of Depreciation

Once a lessee has fully depreciated a pipeline, the transportation charge is limited to operating and maintenance costs. This presents a problem for the owners of these pipelines who point out that the transportation charge will be lower than the actual costs of running a pipeline efficiently once a pipeline is fully depreciated. They further argue that their true costs are not adequately reflected in allowed operating and maintenance costs. Pipelines with depreciated rate bases have at times suggested the adoption of an additional charge called a "management" fee or a "service" fee.

To address this problem, the FERC has approved the collection of management fees. One instance in which this was done occurred in Tarpon.[6] MMS should consider concepts such as this if it is to provide a fair transportation allowance when full depreciation has occurred.

Summary

This paper has illustrated the cost of capital concept and reviewed estimates of the industry's effective cost of capital for pipelines subject to MMS rate methodology. The industry's estimated cost of capital exceeds the return allowed by MMS by 5.4 to 8.3 percentage points. Thus, the transportation allowance provided by the MMS does not even approach the level provided highly regulated public utilities.

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[5] Data on Standard & Poor's BBB rates were supplied by the MMS.
[6] Tarpon Transmission Company, Docket No. RP84-82-004 (Remand) December 26, 1991.

The essential problem with the MMS methodology is that it ignores the use of higher cost equity financing and fails to compensate for income tax effects. By assuming 100% debt financing, the MMS methodology fails to provide firms a return commensurate with the rate of return expected by investors or a return that covers the firm's cost of raising capital. Further, once a pipeline is depreciated, the firm receives no return on its investment and is merely paid a transportation rate that covers variable operating expenses. The management or service fee approach, a form of which has been adopted by the FERC, is one way to address this problem.